CANADA

National Energy Board

Reasons for Decision

ProGas Limited

and

Western Gas Marketing Limited

GH-9-88

June 1989

Gas Exports

National Energy Board

Reasons for Decision

In the Matter of

ProGas Limited

Application Pursuant to Section 21
of the National Energy Board Act for a
Change, Alteration or Variation to
Natural Gas Export Licence GL-98

and

In the Matter of

Western Gas Marketing Limited

Application Pursuant to Section 21
of the National Energy Board Act for a
Change, Alteration or Variation to
Natural Gas Export Licence GL-83

GH-9-88

June 1989

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* R.S.C. 1985, c. N-7 (the Act) and the Regulations made thereunder; and

IN THE MATTER OF applications made by ProGas Limited and Western Gas Marketing Limited, concerning the exportation of natural gas.

HEARD at Calgary, Alberta on 25 January 1989.

BEFORE:

J.-G. Fredette	Presiding Member
J.R. Jenkins	Member
K.W. Vollman	Member

APPEARANCES:

K.J. MacDonald	ProGas Limited
M.J. Samuel	Western Gas Marketing Limited
L.C. Fontaine A.A. Fradsham	Alberta and Southern Gas Co. Limited
L. Keough	Boundary Gas, Inc.
A.M. Bigué	Champlain Pipeline Company
J.H. Farrell	The Consumers' Gas Company Ltd.
B. Pierce	Foothills Pipe Lines (Yukon) Ltd.
J.M. Hunt	Natural Gas Pipeline Company
K.L. Meyer	Pan-Alberta Gas Ltd.
N.D.D. Patterson	TransCanada PipeLines Limited
R.S. Valdis	Union Gas Limited
S. Woronuik	Alberta Petroleum Marketing Commission
J. Robitaille	Procureur général du Québec
J.A. Vockeroth	National Energy Board

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Appendices

The Applications

By application dated 25 October 1988, ProGas Limited (ProGas) sought National Energy Board (Board) approval, pursuant to Section 17 (now Section 21) of the National Energy Board Act (the Act), to amend natural gas export Licence GL-98.

ProGas requested an amendment which would revoke Conditions 1, 2 and 6 of the Licence GL-98 and substitute therefor the following:

"1. The term of this Licence shall commence on the 1st day of November, 1988 and shall end on the 31st day of October, 2000.

2. The quantity of gas that may be exported under the authority of and in accordance with this Licence shall not exceed:

(a) for the period specified in condition 1, a volume not exceeding 33 480 000 000 cubic metres [1.2 Tcf];

(b) for any consecutive twelve (12) month period ending on the 31st day of October, a volume not exceeding 3 100 000 000 cubic metres [109 Bcf];

(c) for any consecutive twenty-four (24) hour period, a volume not exceeding 9 440 900 cubic metres [333 MMcf].

6. Of the quantity of gas authorized for export during each of the periods specified in condition 2, the quantity of gas that may be exported near Monchy, in the Province of Saskatchewan, shall not exceed 50% of the total."

The above amendment would essentially: extend the current daily and annual volume authorizations; remove the step-down in volumes which commences on 1 November 1990; and extend the term of the licence from 31 October 1994 to 31 October 2000. The net effect of these changes is that ProGas has requested that an additional term quantity of 23 315 million cubic metres (823 Bcf) be added to Licence GL-98.

By application dated 16 September 1988, Western Gas Marketing Limited (WGML) as agent for TransCanada PipeLines Limited (TransCanada/TCPL) sought Board approval, pursuant to Section 17 (now Section 21) of the Act, of the following amendments to gas export Licence GL-83:

(i) extend the term of the licence from 31 October 1996 to 15 January 2003;

(ii) authorize the export of the following volumes:

- Maximum Daily Quantity - 2 620.3 10^3m^3 (92.5 MMcfd)
- Maximum Annual Quantity - 959.0 10^6m^3 (33.9 Bcf)
- Maximum Term Quantity - 15 657.3 10^6m^3 (552.7 Bcf);

and

(iii) add a provision to allow for the export of underdeliveries over an extended period of time necessary to export the authorized term quantity.

The above amendments would extend the daily and annual volume authorizations to 15 January 2003 and increase the term quantity authorized under the licence by 6 307 10^6m^3 (222.6 Bcf).

Chapter 2

Reasons for Decision

In considering an application for a licence to export gas, section 118 of the Act requires the Board to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an export impact assessment; and any other factors which the Board considers relevant to its determination of the public interest including net benefits to Canada, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements and markets.

2.1 Complaints Procedure

The complaints procedure is based on the principle that gas should not be authorized for export if Canadian gas users have not had an opportunity to buy gas for their needs on terms and conditions similar to those contained in the proposed export. The complaints procedure thus gives Canadian users an opportunity to object to an export proposal on these grounds.

No Canadian user filed a complaint that they could not obtain additional gas supplies on terms and conditions similar to those contained in the ProGas and WGML applications.

2.2 Export Impact Assessment

The Export Impact Assessment (EIA) helps the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. An applicant is required to assess the ability of Canadian natural gas producers to meet Canadian and export requirements for gas; the impact of the proposed export on domestic natural gas prices; and the ability of Canadian consumers to adjust, if necessary, their energy consumption patterns without substantial difficulty.

The burden of proof is on the applicant to demonstrate to the Board that the proposed export will not likely lead to any major difficulty for domestic consumers in meeting their energy requirements at prevailing market prices. The EIAs presented in support of the proposed gas exports addressed the required issues.

ProGas and WGML concluded that the ability of Canadian gas producers to satisfy domestic and export requirements will not be reduced as a result of their gas export proposal. Both ProGas and WGML were also of the view that Canadian gas prices will be established on the basis of total North American supply and demand. In this context the applicants do not expect the relatively small volumes of the proposed exports to affect future domestic gas prices.

The Board agrees with the overall conclusion that the applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas.

2.3 Gas Supply

In its assessment of gas supply the Board examines the adequacy of contracted reserves and productive capacity to support the applied-for exports. Productive capacity projections are generally adjusted to reflect the applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production.

ProGas

Reserves

ProGas provided estimates of the established reserves under contract which it would use to meet existing commitments and the proposed export. The Board has analyzed the applicant's supply and has prepared its own estimate of the applicant's remaining reserves under contract. The comparison of these estimates with the additional term volume requested by ProGas is presented in Table 2-1.

Table 2-1

Comparison of Reserves Estimates[1] with Additional Term Volume Requested
$10^9 m^3$ (Tcf)

Reserves		
ProGas	**NEB**	**Additional Term Volume Requested**
96.2	86.2	23.3[2]
(3.4)	(3.0)	(0.8)

1 as of 31 December 1987
2 This represents 27 percent of ProGas' estimate of its total requirements of 84.9 billion cubic metres (3.0 Tcf) (Tab: Gas Supply, page 2, Table 1, second to the last column).

The Board's estimate of reserves is lower than the applicant's estimate, primarily because of differences in the interpretation of pool size. Difference in net pay, water saturation and porosity were also contributing factors.

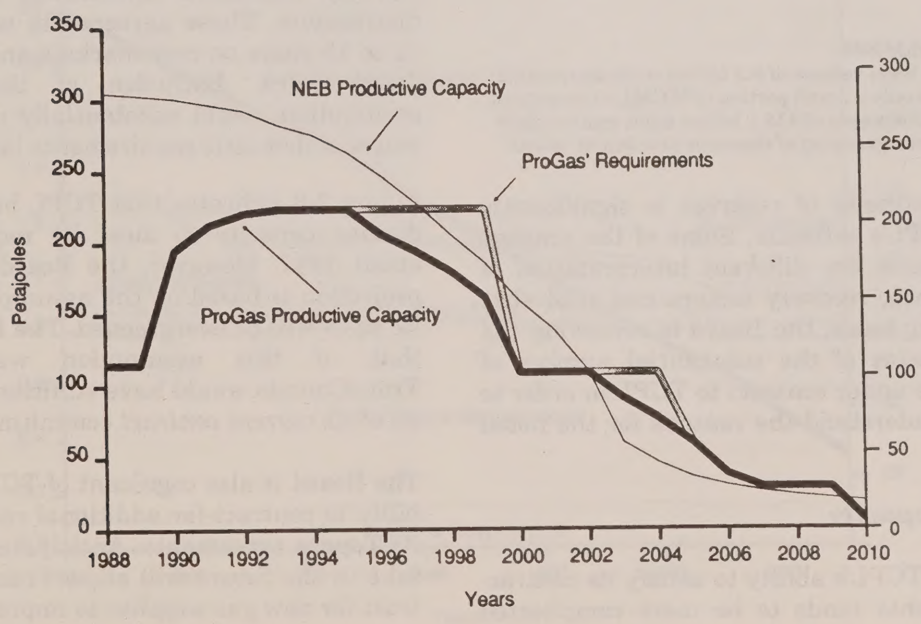
Productive Capacity

Figure 2-1 is an illustration of ProGas' and the Board's estimates of productive capacity. The two projections are based on the reserve estimates shown in Table 2-1 and the requirements estimates submitted by ProGas (underlying data contained in Appendix III, Table A-1). The Board's projection of productive capacity suggests that supply will be insufficient to meet demand during the years 1998-1999, and from 2003 to the end of the projection period. This compares to ProGas' projection which indicates deficiencies in productive capacity from 1996-1999 and 2003-2004.

ProGas stated that increasing its rate-of-take from its producers would remove the productive capacity deficiencies. The applicant testified it would also have the opportunity to develop additional reserves from its contracted lands and might also purchase additional supplies.

Figure 2-1

ProGas Requirements vs Productive Capacity



Despite the evident shortfalls in productive capacity from reserves currently under contract, the Board is satisfied that ProGas will be able to make arrangements to provide sufficient productive capacity to meet its sales requirements.

ProGas stated that it has applied to the Energy Resources Conservation Board (ERCB) for minor amendments to its Alberta removal permit no. GR86-71 which would provide for sufficient permit volumes to cover all of its sales requirements.

WGML

Reserves

WGML provided TCPL's estimates of the established reserves under contract to be used to meet existing commitments and the proposed export. Table 2-2 provides a comparison of TCPL's estimate with the Board's current estimate.

Table 2-2

Comparison of Reserves Estimates[1] with Additional Term Volume Requested
$10^9 m^3$ (Tcf)

Reserves: TCPL	Reserves: NEB	Additional Term Volume Requested
675.3	486.8	6.3[2]
(23.8)	(17.2)	(0.2)

1 as of 31 December 1987.
2 The additional term volume of 6.3 billion cubic metres (0.2 Tcf) represents only a small portion of WGML's estimate of their total requirements of 815.1 billion cubic metres (28.8 Tcf) (includes evergreening of domestic and export sales).

The Board's estimate of reserves is significantly lower than TCPL's estimate. Some of the reasons for this difference are different interpretation of pool performance, recovery factors and pool size. On a continuing basis, the Board is reviewing the reserves estimates of the substantial number of pools which are under contract to TCPL in order to identify and understand the reasons for the noted difference.

Productive Capacity

Assessment of TCPL's ability to satisfy its contractual commitments tends to be more complicated than that for other companies. This is largely due to the fact that the company is both the main supplier of Canadian domestic gas requirements and a major exporter.

Figure 2-2 shows TCPL's estimates of requirements and productive capacity (underlying data contained in Appendix III, Table A-2). The projection of productive capacity is based on TCPL's estimate of reserves and requirements. The requirements projection includes evergreened domestic and export sales, as well as the applied-for volumes. TCPL's projections indicate that productive capacity will be adequate to meet requirements until about 1995.

Figure 2-3 shows the Board's projections of TCPL's requirements and productive capacity (underlying data is contained in Appendix III, Table A-3). The projection of productive capacity is based on the Board's assessment of TCPL's reserves and requirements. The requirements estimates are the same as those used by TCPL, with the exception of export sales. Since TCPL's exports are subject to Board approval, the Board has included in its estimate only authorized export levels and the export volumes sought in this application. Corresponding changes were also made to the mainline uses estimates.

With regard to domestic sales, the Board notes that both the TCPL and Board estimates assume evergreening. Thus, in principle TCPL and the Board have included extensions of WGML's recently negotiated agreements with the eastern distributors. These agreements were for terms of 12 to 15 years on core markets and 3 to 5 years on direct sales. Exclusion of this evergreening assumption would substantially reduce both estimates of domestic requirements later in the period.

Figure 2-3 indicates that TCPL has sufficient productive capacity to meet its requirements until about 1997. However, the Board notes that this projection is based on the assumption that domestic sales will be evergreened. The Board is satisfied that, if this assumption were not made, TransCanada would have sufficient supply to meet all of its *current contract* commitments.

The Board is also cognizant of TCPL's current inability to contract for additional reserves in light of its Topgas agreements. Anticipated higher rates of take in the future will allow TransCanada to contract for new gas supplies to improve its situation.

Figure 2-2

TCPL's Estimates of Requirements and Productive Capacity

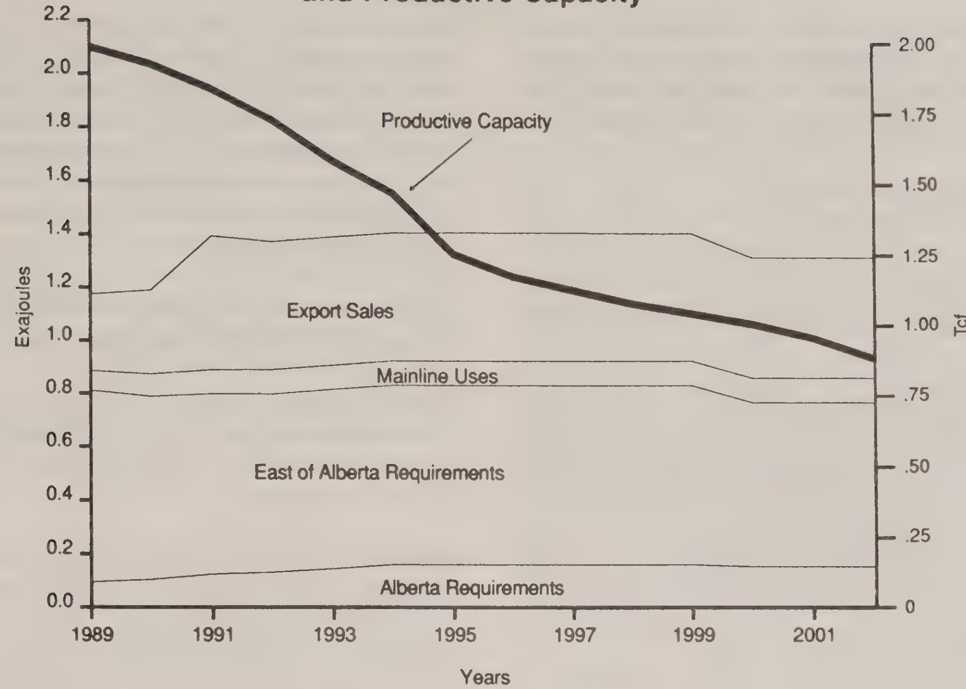
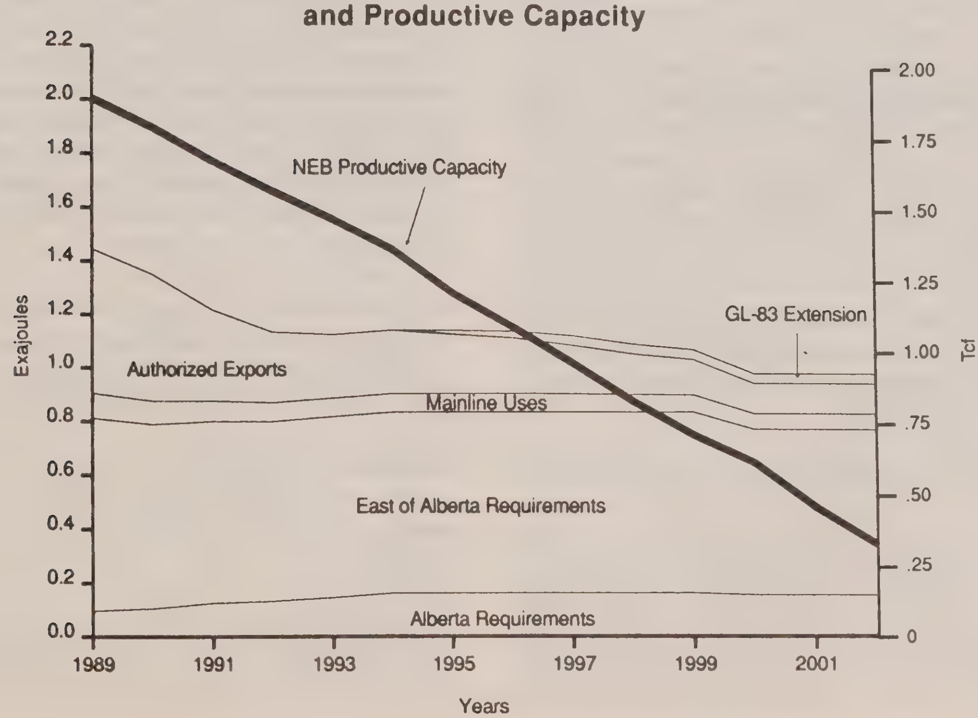


Figure 2-3

NEB Estimates of TCPL Requirements and Productive Capacity



TCPL holds several removal permits with the majority of its reserves included in removal permit TC 85-1.

The applicant stated that it would apply to the ERCB in the near future for a minor term extension to its removal permit in order to satisfy the Boundary Gas Inc. (Boundary) requirements.

2.4 Gas Sales Contracts

ProGas

ProGas currently sells gas to four U.S. customers, ANR Pipeline Company (ANR), Natural Gas Pipeline Company of America (Natural), Tennessee Gas Transmission Company (Tennessee), and Texas Eastern Transmission Corporation (Tetco), in accordance with long-term gas sales agreements negotiated in early 1979. The four agreements expire on 31 October 2000 and thus, their terms correspond to the licence term extension applied for. Under the terms of the four agreements, each of the four U.S. customers purchases 2 125 $10^3m^3/d$ (75 MMcfd) of gas from ProGas.

Under the terms of the ANR Gas Sales Agreement, ANR is to pay an export price composed of a monthly demand charge and a commodity charge. The monthly demand charge is equal to the sum of the NOVA Corporation of Alberta (NOVA), TransCanada, and ProGas tolls and charges. ANR has a one-time right to request a renegotiation of the demand charge, subject to ProGas' right to reimpose a minimum take provision in the contract. The specified commodity charge is renegotiable annually upon written request by either party and with the purpose of ensuring an export price that is competitive.

The most recent Amending Agreement dated 1 December 1988 was approved by the Board in January 1989, pursuant to subsection 35(2) of the NEB Part VI Regulations.

Under the terms of the new 7 October 1988 Gas Sales Agreement between ProGas and Natural, Natural is to pay a demand-commodity export price. The monthly demand charge is the sum of the NOVA, Foothills Pipe Lines (Yukon) Ltd. (Foothills), and ProGas tolls and charges and is to be redetermined each month, as required. The specified commodity charge component varies in accordance with the season and with the load factor, and is renegotiable annually upon request by either party.

The Agreement provides for a minimum annual quantity equal to 75 percent of the sum of the daily contract quantities in the winter period, plus 50 percent of the sum of the daily contract quantities in the summer period. ProGas noted that that equates to an overall minimum take obligation of 60 percent, which ProGas considered to be reasonable under current market conditions.

All of the gas to be purchased by Natural is to be delivered at Monchy, Saskatchewan.

The 7 October 1988 Gas Sales Agreement with Natural was approved by the Board in November 1988, pursuant to subsection 35(2) of the NEB Part VI Regulations.

The 17 May 1979 ProGas/Tennessee Gas Sales Contract, most recently amended by an Amending Agreement dated 25 August 1986, provides that Tennessee is to pay ProGas a demand-commodity export price. The monthly demand charge recovers the monthly demand toll on the NOVA and TransCanada pipeline systems, as well as a monthly charge for ProGas' services.

The total commodity charge is comprised of a "Base Commodity Charge" and a "Market Commodity Charge". ProGas noted that the "Base Commodity Charge" is to apply to the minimum monthly quantity equal to 20 percent of the sum of the daily contract quantities for the month. The "Base Commodity Charge" is the weighted average cost of gas of Tennessee's gas supply portfolio. For purchases above the minimum monthly quantity a "Market Commodity Charge" is to be negotiated on a monthly basis and thus, be responsive to changing conditions in the market areas served by Tennessee. All gas purchases above the minimum monthly quantity are to be determined by mutual agreement between Tennessee and ProGas.

The 25 August 1986 Amending Agreement was approved by the Board in November 1986, pursuant to subsection 35(2) of the NEB Part VI Regulations.

In accordance with the terms and conditions of the ProGas/Tetco Gas Sales Agreement dated 1 November 1986, most recently amended by an

Amending Agreement dated 9 July 1987, Tetco is to pay ProGas a demand-commodity price. The demand charge component ensures recovery of the monthly demand toll on the NOVA and TransCanada pipeline systems, as well as ProGas' monthly service charge. The commodity charge is based upon the commodity charge in Tetco's "Rate Schedule DCQ" filed with the Federal Energy Regulatory Commission (FERC), less the cost of transportation from Emerson, Manitoba to the point of interconnection with the Tetco system.

The Agreement is renegotiable on an annual basis upon request by either party and provides for a minimum annual quantity which varies on an annual basis in accordance with the ratio of U.S.-sourced gas taken by Tetco to the quantity of gas available from Tetco's pipeline and field suppliers under supply contracts having a minimum term of three years.

The Board notes that the amendments to the gas sales contracts with each of the four U.S. customers supporting the licence extension to 31 October 2000 have been approved by the Board as contract amendment filings under subsection 35(2) of the NEB Part VI Regulations.

TransCanada/WGML

In accordance with the Gas Purchase Contract (the Phase 2 Contract) dated 14 September 1987, TransCanada has agreed to sell to Boundary a daily contract quantity (DCQ) of 2 620.3 $10^3m^3/d$ (92.5 MMcfd) of gas at Niagara Falls, Ontario during the period ending 31 October 1996. The term of the contractual arrangement was subsequently extended to 15 January 2003 under the terms of an executed Precedent Agreement dated 31 August 1988.

In accordance with the Gas Purchase Contract, Boundary is to pay TransCanada an export price consisting of a monthly demand charge and a commodity charge. The demand charge component is equal to the sum of the average adjusted demand charge billed by NOVA to TransCanada and the monthly demand charge for firm transportation service on the TransCanada system to the Niagara Falls, Ontario export point. The commodity component of the export price is arrived at by subtracting the monthly demand charge from a negotiated initial base price which is adjusted monthly to reflect changes in the New York Weighted Average Price (NYWAP). The NYWAP is comprised of major competing alternate fuels (i.e. gas and No. 2 and 6 fuel oils) available to the New York State market.

Either party has the right to request price renegotiation upon suitable written request, and the price is subject to arbitration if required. The contract stipulates that, in the event Boundary takes less than 60 percent of the annual contract quantity (ACQ), the resulting deficiency is to be made up in the next succeeding year after first taking the ACQ. TransCanada has the right to permanently reduce the DCQ in the event that Boundary has been unable to make up previously incurred deficiencies.

TransCanada argued that the Boundary Gas Purchase Contract provides the necessary incentives to ensure that the gas will be taken. In particular, TransCanada noted that the pricing mechanism will ensure that the Canadian-sourced gas is always competitive by being responsive to prices of competing energy in the markets served by the Repurchasers.

The Board notes that the First Amendment to the Phase 2 Gas Purchase Contract still requires Board approval under subsection 35(2) of the NEB Part VI Regulations.

2.5 Markets

ProGas

Under the authority of export Licence GL-98, ProGas exports gas to ANR, Natural, Tennessee and Tetco.

The gas sold to ANR is for resale to some fifty-one local distribution companies (LDCs) serving various states, including Wisconsin and Michigan. ProGas noted that recent purchases of system supply by ANR's LDC customers have declined owing to the availability of relatively low-priced spot gas off the ANR system. ANR expressed confidence that its firm system sales will improve as its traditional LDC core market returns to ANR's system supply.

ProGas' evidence demonstrated that ANR's total supply requirements will increase by approximately 36 percent to the year 2001 and that this demand will increasingly be served by Canadian-sourced gas. ProGas noted that despite ANR's

recent marketing difficulties, ANR has recognized its contractual obligation and has continued to purchase gas from ProGas.

Gas exported to Natural is resold to fifty LDCs serving various states from Texas to Illinois. Some 96 percent of Natural's system supply sales take place in Illinois, the main market being the Chicago area.

ProGas indicated that, like many U.S. interstates, Natural has seen a decline in its system supply sales and an increase in its transporter role, as the LDCs have increasingly relied on the U.S. spot market.

ProGas noted that despite Natural's past marketing difficulties, Natural has continued its demand charge payments, and maintained its minimum gas purchase obligations to ProGas.

ProGas noted that Natural has embarked on an aggressive marketing strategy to regain its lost market share by, among other things, reducing its gas purchase costs. This new strategy is expected to result in Natural purchasing all of the gas available under its gas sales contract with ProGas during the contract year ending 31 October 1988.

Tennessee's market is comprised of both LDCs and other interstate pipeline systems, including Midwestern Gas Transmission Company (Midwestern). Tennessee serves several states from Texas to Massachusetts. ProGas noted that despite Tennessee opening its system to non-discriminatory transportation under FERC Order 436, this new status as an open-access transporter did not result in a major shift from sales to transportation services on its system. Tennessee has been able to retain a relatively strong market for system supply gas due, in part, to the continued growth in gas demand in the U.S. Northeast market.

Tennessee's supply-demand balance indicated a supply deficiency starting as early as 1990 and an increase in imports of Canadian-sourced gas over the period ending 2001.

Tetco supplies gas to several LDCs serving markets in the U.S. Northeast, as well as to Algonquin Gas Transmission Company (Algonquin) and Consolidated Gas Transmission Corporation (Consolidated). Algonquin serves the LDC markets of several eastern seabord states, including New York, Rhode Island, and Massachusetts. Consolidated supplies gas to several LDC markets, including those located in New York, Ohio, and Pennsylvania. Consolidated's gas purchases from Tetco have fallen in the recent past as it too has experienced loss of market share due, in part, to an increasing portion of its traditional market choosing to purchase directly.

ProGas noted that it is anticipated that Tetco will require additional, incremental volumes from ProGas to serve a growing U.S. Northeast market, including the electric generation and firm cogeneration markets.

Tetco's deliverability versus requirements forecast indicated shortfalls in gas supply starting in 1990.

The Board is satisfied that ProGas' evidence has demonstrated a requirement for Canadian gas to serve the long-term firm requirements for its four U.S. customers.

TransCanada/WGML

Under the authority of export Licence GL-83, TransCanada exports gas to Boundary at Niagara Falls, Ontario. Boundary was incorporated to contract for the purchase of gas from TransCanada on behalf of fifteen U.S. LDCs collectively known as the "Boundary Repurchasers".

The Boundary Repurchasers, who are entitled to purchase gas from Boundary in proportion to their percentage of stock ownership in Boundary, serve U.S. markets in the states of New York, New Jersey, Connecticut, Rhode Island, Massachusetts, New Hampshire and Maine.

TransCanada noted that since Boundary commenced importing Canadian gas in November 1984, the average load factor has been at, or close to, 100 percent of the contracted maximum daily quantity. TransCanada pointed out that Boundary has been able to maintain this high level of performance since 1984 owing to its market-based pricing mechanism which ties the Canadian export price to the price of competing long-term pipeline gas sales and to alternate fuels available to the market place. As well, the "least-cost purchasing policies" of the Boundary Repurchasers and the contract provision which permits the Boundary Repurchasers to make available any unneeded gas

to other Boundary Repurchasers have all contributed to Boundary's high load factor takes.

A supply/demand balance submitted by TransCanada, which was compiled on the basis of data submitted by each of the Boundary Repurchasers, demonstrated the continued dependence of the Boundary Repurchasers on Canadian-sourced gas through to the contract year ending 31 October 2003.

TransCanada indicated that the Boundary Repurchasers will require additional gas supply to serve peak demands and new market growth, including the growing gas requirements of the electric power generation market. Strong economic growth in the U.S. Northeast is expected to continue well into the next decade and hence, the need for long-term secure gas supplies.

Boundary noted that the Boundary Repurchasers are interested in matching their gas supply with the availability of transportation service on Tennessee. That transportation service is available until January 2003 without the need to construct additional capacity.

In summary, TransCanada submitted that on the basis of Boundary's strong historical export performance to date and the supply/demand balance which supported a continued need for Canadian-sourced gas, TransCanada had demonstrated the existence of U.S. markets for the proposed licence extension.

The Board is satisfied that WGML has demonstrated the long-term need for Canadian gas in the market areas served by the Boundary Repurchasers.

2.6 Transportation Arrangements

ProGas

ProGas has executed transportation contracts with NOVA and TransCanada for the delivery of gas to the Emerson, Manitoba export point to the years ending 31 October 2001 and 31 October 2000, respectively. Likewise ProGas has concluded transportation arrangements with Foothills for the delivery of gas to Monchy, Saskatchewan through to the year ending 31 October 1988. ProGas indicated that negotiations are currently underway to extend the term of the existing transportation service agreement with Foothills for an initial six years to 31 October 1994, and for a further six years to 31 October 2000.

Gas sold to ANR is transported from Alberta to the Emerson, Manitoba export point via the NOVA and TransCanada facilities, and via Midwestern to a point of interconnection with the ANR system. ANR's existing transportation service contract with Midwestern expires on 31 October 1992.

Gas sold to Natural is transported via the NOVA and Foothills facilities to the Monchy, Saskatchewan export point. In the U.S., the Natural imports are transported on the Northern Border Pipeline Company (Northern Border) and Northern Natural Pipeline Company (Northern Natural) systems for delivery to Natural. Existing transportation service arrangements with Northern Border and Northern Natural will have to be extended to conform with the licence extension applied for.

Gas sold to Tennessee and Tetco is transported on the NOVA and TransCanada systems to the Emerson, Manitoba delivery point, and via the Great Lakes Gas Transmission Company (Great Lakes) and ANR systems for delivery to Tennessee and Tetco. With the exception of the Tetco/ANR transportation service, all other U.S. downstream transportation service arrangements associated with the Tennessee and Tetco exports are in place to 31 October 2000.

ANR, Northern Border, and Northern Natural are open-access transporters under FERC Order 436/500.

TransCanada/WGML

All contractual arrangements for the delivery of the Boundary exports to Niagara Falls, Ontario have been concluded with NOVA and TransCanada. In the U.S., transportation arrangements and facilities are in place through to the year 2003 to permit Tennessee to continue to deliver the Boundary volumes to each of the Repurchasers.

2.7 Benefit-Cost Analysis

ProGas

Table 2-3 shows the summary results of the benefit-cost analysis which ProGas submitted in support of its application. The study indicates that the

Table 2-3

ProGas' Benefit-Cost Analysis of its Export Proposal
(millions of 1988 Canadian dollars at an 8% discount rate)

	Low Case	High Case
BENEFITS		
Gas Exports	1637	1637
Sales of By-products	257	257
TOTAL	**1894**	**1894**
COSTS		
Production Costs	362	362
Transportation Costs	19	19
User Cost	558	957
TOTAL	**939**	**1338**
NET SOCIAL BENEFIT	**956**	**557**
BENEFIT/COST RATIO	**2.02**	**1.42**

applied-for exports should yield net benefits to Canada ranging between approximately $557 million and $956 million in the applicant's high and low cases respectively, using an 8 percent discount rate.

The applicant's low and high world oil price scenarios are distinguished only by different assumptions about future natural gas supply costs. Future supply costs are assumed to increase more rapidly in the high case scenario than in the low case scenario, resulting in higher estimated user costs in the high case scenario. As shown in Table 2-3, all other cost and revenue projections are identical in the low and high cases.

Export prices were based on a forecast of gas prices in the Chicago area which, in turn, were based on a forecast of the Chicago West Texas Intermediate oil price. After adjustments for transportation charges were made, export prices at Emerson were forecast to be Cdn $2.75./GJ ($2.95/MMBtu) (1988$) in the year 1990 and to increase to Cdn. $3.95/GJ ($4.24/MMBtu) (1988$) by 2000. Export prices at Monchy were forecast to be Cdn. $2.63/GJ ($2.82/MMBtu) (1988$) in 1990 and to increase to Cdn. $3.83/GJ ($4.11/MMBtu) (1988$) by 2000. The forecast load factor used in the study was 90 percent but, in final argument, the applicant indicated that an 80 percent load factor might be more appropriate. By-product revenues were estimated to be equal to 12 percent of the world oil price per unit of marketable gas delivered to NOVA.

The applicant argued that no capital expenditures on new facilities were required for the applied-for exports because facilities were already in place to accommodate its existing exports.

As no capital expenditures were deemed necessary to support the applied-for exports, transportation costs were comprised of only incremental operating costs on the NOVA, Foothills, and TCPL systems. Fuel gas costs were included in the estimate of field production costs, based on existing average fuel cost ratios on NOVA, Foothills, and TCPL.

The applicant submitted that it had adequate reserves to support the applied-for licence volumes and that field production costs would average $0.72/GJ ($0.77/MMBtu). As ProGas' exports would come from existing reserves, these costs were assumed to be the same in the applicant's low and high case scenarios.

The applicant estimated the user costs to be associated with the forecast export volumes using the supply cost estimates and domestic natural gas demand forecasts outlined in the low and high case scenarios of Board staff's September 1988 report, *Canadian Energy, Supply and Demand 1987-2005.* In order to estimate user costs attributable to an incremental export, it is necessary to prepare a forecast of total gas production in absence of the applied-for export. In selecting its forecast, ProGas chose to use the lesser of a February 1988 Independent Petroleum Association of Canada (IPAC) forecast or currently licensed export volumes. Because licensed export volumes in effect at the time of ProGas' application drop off sharply after 1994, the applicant's methodology results in a forecast in which exports drop below 8.5 $10^9 m^3$/year (300 bcf/year) after 1994 and decline thereafter.

The applicant maintained that its methodology was appropriate because it focussed the analysis on the user cost of export authorizations over and above currently-licensed levels.

In summary, ProGas argued that its applied-for exports would provide net benefits to Canada. No intervenors disputed the reasonableness of the submitted results and none argued that the proposed exports would not yield net economic benefits to Canada.

The Board prepared its own benefit-cost analysis of ProGas' application. In the Board's analysis the forecast revenue stream and future cost production costs were calculated under a high and low oil price scenario. These two scenarios were consistent with the price and cost projections contained in the low and high oil price scenarios in the Board's 1988 Supply and Demand report.

In light of the low load factors on ProGas' sales in recent years, it would have been more appropriate for the applicant to use a forecast load factor in the range of 70 to 80 percent, rather than the submitted 90 percent. The Board used a 75 percent load factor in the base case in both its low oil price and high oil price scenarios and performed sensitivities about this value.

The Board is of the view that the applicant's estimate of the initial price is overly optimistic. Although the average export price is forecast to increase more rapidly in the Board's high case than in the applicant's forecast, the Board nonetheless projects a lower net present value for the export revenue stream in both its low and high oil price scenarios than is estimated by ProGas, even after adjusting for the lower load factor assumed by the Board.

The Board notes that, to be consistent with the low and high cases presented by the applicant with respect to user cost, the applicant could have provided separate forecasts of revenues for its high and low cases.

The Board finds the applicant's estimates of fuel gas costs and production costs to be reasonable.

With respect to transportation costs, the Board does not believe that it is appropriate to allocate zero facilities costs to the applied-for licence extension. This might be appropriate if pipeline system throughputs were projected to decline during the extension period, in which case the capacity required by ProGas would rest unused in the absence of ProGas' exports. However, the Board expects that, in the circumstances of this application, it is reasonable to expect that throughputs on TransCanada's western section are likely to rise throughout the applied-for licence term and, in the absence of ProGas' export, the available pipeline capacity could be used by other shippers. Hence, the ProGas application will result in additional costs to Canada and these costs should be reflected in the benefit-cost analysis of the application.

In estimating the capital costs on TransCanada associated with ProGas' application, the Board considered that because throughput on TransCanada's western section can reasonably be expected to grow over time, any new facilities required to accommodate ProGas' exports would effectively constitute an advancement of facilities that would eventually be required in any event. Thus, the theoretically correct measure of facilities costs to allocate to ProGas would be equal to:

(1) the net present value of expected facilities cost expenditures including ProGas' exports; minus

(2) the net present value of the expected facilities cost expenditures excluding ProGas' exports.

To estimate capital costs in this manner would require a forecast of annual facilities cost expendi-

tures with and without the applied-for export licence. However, the Board considers that the marginal cost of expansion on the relevant section of the TransCanada system is approximately constant over the forecast period. As a result, the incremental capital expenditures on the TransCanada western section attributable to the ProGas licence extension are approximately equal to the costs of advancing over the applied-for licence term the direct capital expenditures associated with a capacity expansion equivalent to ProGas' transportation requirements.

The use of this methodology yielded a facilities cost estimate of $59 million (1988$) on TransCanada attributable to the ProGas application. Incremental facilities costs on the Foothills and NOVA systems were estimated in a similar fashion, yielding cost estimates of $12 million and $21 million respectively (1988$).

In addition, the Board included a cost to reflect ProGas' use of the Great Lakes system. If ProGas' exports were not to proceed, firm transportation capacity of 150 MMcf/day (4 250 103m3/day) would revert to TransCanada. This release of capacity on Great Lakes would allow TransCanada to avoid more expensive transportation costs on its central section. Thus, the cost to Canada associated with ProGas' continued use of the Great Lakes system is the difference between the transportation costs on the combined Central Section/Great Lakes system minus the cost of service associated with 150 MMcf/day of ProGas' capacity on Great Lakes. The Board estimates the present value of these costs to be about $25 million.

The Board does not agree with the methodology used by the applicant in calculating user costs. The applicant's forecast of export demand in the absence of its proposed exports appears to severely understate the exports that are likely to flow during the forecast period. Indeed, the applicant's forecast implies that pipeline facilities would be under-utilized as existing licences expire and that alternative export market opportunities for Canadian natural gas would not exist.

A further undesirable aspect of using licensed exports for the demand forecast would be the potential unequal treatment of export applicants; i.e. two licence applicants with the same volumes and contractual pricing arrangements would be evaluated differently if it so happened that the level of licensed exports were different at the time each application was received.

User cost arises because increased production from existing reservoirs accelerates the timeframe in which higher cost reservoirs must be exploited. Thus, user cost is a function of the gas production profile over time and bears no direct relation to the level of licensed exports. In the Board's view, the correct approach is to use a reasonable projection of export demand in the absence of the applied-for export and, as with other components of the analysis, to conduct tests of the sensitivity of the user cost estimates to lower or higher levels of future exports.

In estimating user cost, the Board forecast both domestic and export demand according to the projections in the low and high cases of its 1988 Supply and Demand report. The applied-for export volumes were then deducted from these forecasts to determine the production profile in the absence of the export. The total incremental production costs attributable to the applied-for export were then calculated as:

(1) the net present value of the total production costs of all forecast production with the export; minus

(2) the net present value of the total production costs of all forecast production without the export.

Subtracting the applicant's own direct production costs from the remainder of (1) minus (2) yields the estimated user costs attributable to the applied-for export. The Board's methodology yielded slightly higher user costs on a per unit basis than those estimated by the applicant.

The results of the Board's base case benefit-cost analysis in the low and high oil price scenarios are shown in Table 2-4. The Board's analysis indicates lower expected net benefits to Canada than the submitted analysis, primarily because the Board expects that the actual load factor will be less than that estimated by the applicant and because the Board imputed additional facilities costs to the application whereas the applicant did not. Nonetheless, the base case analysis indicates that the applied-for exports are likely to yield net economic benefits to Canada.

Table 2-4

Board's Benefit-Cost Analysis of ProGas' Export Licence Application
(millions of 1988 Canadian dollars at an 8 percent discount rate)

	Low Oil Price Scenario	High Oil Price Scenario
BENEFITS		
Gas Export Revenue	1039	1315
By-Product Revenue	164	281
TOTAL[1]	**1203**	**1596**
COSTS		
Production Costs	277	277
Transportation Costs		
Operating Costs	16	16
Capital Costs	91	91
User Cost	672	1135
TOTAL	**1056**	**1519**
NET SOCIAL BENEFITS	**147**	**77**
BENEFIT/COST RATIO	**1.14**	**1.05**

1 The Board's estimated total benefits are lower than the applicant's primarily because the Board's analysis assumes a lower load factor.

Table 2-5

Sensitivity Analyses of ProGas' Export Licence Application
(net benefits in millions of 1988 Canadian dollars)

	Low Oil Price Scenario	High Oil Price Scenario
BASE CASE*	147	78
Different Discount Rates		
6% Discount Rate	148	30
10% Discount Rate	95	76
Different U.S. Gas Prices		
10% Higher	227	185
10% Lower	67	(30)
Load Factor Sensitivities		
60% Load Factor	147	91
90% Load Factor	149	65
User Cost Sensitivities		
Exports at 1.2 EJ (1.1 Tcf)/yr	203	159
Exports at 1.8 EJ (1.7 Tcf)/yr	111	40

*Note: The base case assumes a 75% load factor, export demand rising to approximately 1.5 EJ (1.4 Tcf) per year by 1994, and an 8% discount rate.

The Board conducted sensitivity analyses of its results using different discount rates, higher and lower U.S. gas prices, different load factors and, for the purposes of the user cost calculation, different export demand forecasts. As shown in Table 2-5, the results of the sensitivity analyses indicate that the applied-for exports should yield net benefits under a range of plausible assumptions.

WGML

Table 2-6 shows the summary results of the benefit-cost analysis which WGML submitted in support of its application. The study indicates that the applied-for exports should yield net benefits to Canada ranging between approximately $93 million (1988$) and $171 million (1988$) in the Applicant's high and low cases respectively, using an 8 percent discount rate.

The Applicant's low and high world oil price scenarios are distinguished only by different assumptions about future natural gas supply costs. Future supply costs are assumed to increase more rapidly in the high case scenario than in the low case scenario, resulting in higher estimated user costs in the high case scenario. As shown in Table 2-6, all other cost and revenue projections are identical in the low and high cases.

The Applicant adapted a forecast of the Niagara border price prepared by TransCanada Pipeline Limited in its 1989-90 Facilities Application, adjusted to constant 1988 dollars, to forecast the export price. The export price at Niagara was forecast to be Cdn. \$3.31/GJ (\$3.55/MMBtu) (1988\$) in 1996 and to increase to Cdn. \$4.06/GJ (\$4.36/MMBtu) (1988\$) by 2003.

The forecast load factor used in the study was 100 percent.

The Applicant argued that no capital expenditures on new facilities were required for the applied-for exports because facilities were already in place to accommodate its existing exports.

Table 2-6

WGML's Benefit-Cost Analysis of its Export Proposal
(millions of 1988 Canadian dollars at an 8% discount rate)

	Low Case	High Case
BENEFITS		
Gas Exports	337	337
Sales of By-products	56	56
TOTAL	**393**	**393**
COSTS		
Production Costs	79	79
Transportation Costs	11	11
User Cost	132	210
TOTAL	**222**	**300**
NET SOCIAL BENEFIT	**171**	**93**
BENEFIT/COST RATIO	**1.77**	**1.31**

As no capital expenditures were deemed necessary to support the applied-for exports, transportation costs were comprised of only incremental operating costs on the NOVA and TCPL systems. Fuel gas costs were included in the estimate of field production costs, based on existing average fuel cost ratios on NOVA and TCPL.

The Applicant submitted that it had adequate reserves to support the applied-for licence volumes and that field production costs would average \$0.72/GJ (\$0.77/MMBtu). As WGML's exports would come from existing reserves, these costs were assumed to be the same in the Applicant's low and high case scenarios.

The Applicant estimated the user costs to be associated with the forecast export volumes using the supply cost estimates and domestic natural gas demand forecasts outlined in the low and high case scenarios of Board staff's September 1988 report, *Canadian Energy, Supply and Demand 1987-2005.* In order to estimate user costs attributable to an export, it is necessary to prepare a forecast of gas production without the applied-for export. In forecasting export demand on an annual basis, WGML used the lesser of a February 1988 Independent Producers Association of Canada (IPAC) forecast or currently licensed export volumes. Because licensed export volumes in effect at the time of WGML's application drop off sharply after 1994, the Applicant's methodology results in a forecast in which exports drop below 8.5 10^9m^3/year (300 Bcf/year) after 1994 and decline thereafter.

The Applicant maintained that its methodology was appropriate because it focussed the analysis on the user cost of export authorizations over and above currently licensed levels.

In summary, WGML argued that its applied-for exports would provide net benefits to Canada. No intervenors disputed the reasonableness of the submitted results and none argued that the proposed exports would not yield net economic benefits to Canada.

The Board prepared its own benefit-cost analysis of WGML's application. In the Board's analysis the forecast revenue stream and future production costs were calculated under a high and low oil price scenario. These two scenarios were consistent with the price and cost projections contained in the low and high oil price scenarios in the Board's 1988 Supply and Demand report.

Although load factors on sales to Boundary have recently been close to 100 percent, the Board believes that it is overly optimistic to assume that a 100 percent load factor can consistently be maintained. The Board assumed a 95 percent load factor for its base case analysis in both the low and high oil price scenarios.

The price stream used in the Applicant's analysis falls between the projections in the Board's low and high cases, and is considered to be a reasonable projection. The Board notes however, that, to be consistent with the low and high cases submitted with respect to user cost, the Applicant could have provided separate forecasts of revenues for its high and low cases.

The Board finds the Applicant's estimates of its production costs to be reasonable.

With respect to transportation costs, the Board does not believe that it is appropriate to allocate zero facilities costs to the applied-for licence extension. This might be appropriate if pipeline system throughputs were projected to decline during the extension period, in which case the capacity required by WGML would rest unused in the absence of WGML's exports. However, the Board expects that, in the circumstances of this application, it is reasonable to expect that throughputs on TransCanada's western and central sections are likely to rise throughout the applied-for licence term. In the absence of WGML's exports, the available pipeline capacity could be used by other shippers. Hence, the extension of WGML's license will result in additional costs to Canada and these costs should be reflected in the benefit-cost analysis of the application.

In estimating the capital costs on TransCanada associated with WGML's application, the Board used the same methodology outlined in the foregoing discussion on facilities costs related to ProGas' application. Use of the Board's methodology yields facilities cost estimates of $45 million (1988$) on TransCanada and $5 million (1988$) on NOVA attributable to the WGML application.

For the reasons outlined in the discussion of ProGas' benefit-cost analysis, the Board does not agree with the methodology used by the Applicant in calculating user costs. Use of the Board's methodology, also previously discussed, yields higher user costs on a per unit basis than that estimated by the Applicant.

The results of the Board's base case benefit-cost analysis in the low and high oil price scenarios are shown in Table 2-7. In the low oil price scenario, the Board's analysis yields notably lower expected net benefits to Canada than the Applicant's analysis. This is primarily because the Board forecast higher per unit user costs than the Applicant and because the Board has imputed facilities costs to the application, whereas WGML did not.

The benefit-cost ratios in the Board's high oil price case and in the Applicant's high case are approximately equal. This is because the higher gas export revenue, relative to the Applicant's, expected by the Board in the high oil price scenario is offset by the Board's higher forecast user costs and the Board's imputed facilities cost.

In summary, the Board's analysis indicates that the applied-for exports are likely to yield net economic benefits to Canada.

The Board conducted sensitivity analyses of its results to different discount rates, higher and lower world oil prices and U.S. gas prices, lower load factors and, for the purposes of the user cost calculation, different export demand forecasts. As shown in Table 2-8, the results of the sensitivity analyses indicate that the applied-for exports should yield net benefits over most of the range of assumptions tested with respect to the key variables in the analysis.

Table 2-7

Board Staff Benefit-Cost Analysis of WGML's Export Licence Application
(millions of 1988 Canadian dollars at an 8 percent discount rate)

	Low Oil Price Scenario	High Oil Price Scenario
BENEFITS		
Gas Export Revenue	299	435
By-Product Revenue	43	75
TOTAL	**342**	**510**
COSTS		
Production Costs	69	69
Transportation Costs		
Operating Costs	10	10
Capital Costs	50	50
User Cost	202	331
TOTAL	**331**	**460**
NET SOCIAL BENEFITS	**10**	**50**
BENEFIT/COST RATIO	**1.03**	**1.11**

Table 2-8

Sensitivity Analyses of WGML's Export Licence Application
(net benefits in millions of 1988 Canadian dollars)

	Low Oil Price Scenario	High Oil Price Scenario
BASE CASE*	**10**	**50**
Different Discount Rates		
6% Discount Rate	19	57
10% Discount Rate	(9)	36
Different World Oil Prices		
10% Higher	24	74
10% Lower	(4)	25
Different U.S. Gas Prices		
10% Higher	24	66
10% Lower	(3)	33
Load Factor Sensitivities		
80% Load Factor	9	47
60% Load Factor	(12)	13
User Cost Sensitivities		
Exports at 1.2 EJ (1.1 Tcf)/yr	24	68
Exports at 1.8 EJ (1.7 Tcf)/yr	1	37

*Note: The base case assumes a 95% load factor, export demand rising to approximately 1.5 EJ (1.4 Tcf) per year by 1994, and an 8% discount rate.

Disposition

Having considered all matters relevent, including whether the volumes to be exported are surplus to reasonable foreseeable Canadian requirements, the Board has concluded that the proposed licence extensions are in the public interest and that the gas to be exported is surplus to Canadian requirements. Thus, the Board has decided to issue licence amendments to both ProGas and WGML. Appendices I and II contain the terms and conditions of these proposed amendments. All of the applicants' requests have been granted with the exception of WGML's requests for a term extension provision for underdeliveries. The Board was not convinced by WGML's arguments regarding the merit of such a provision.

The Board notes that to implement the decision, Governor in Council approval of the licence amendments is required.

The Board's decision is based on the procedure outlined in the introduction to Chapter 2. Of particular note was the absence of any complaints or opposition to the proposed extensions. In addition, both applicants filed Export Impact Assessments which demonstrated that the proposed licence amendments would have little or no impact on total production, gas prices and consumption patterns. The Board agrees with these overall conclusions.

The Board also assessed a number of public interest items, including gas supply, markets, gas sales contracts, transportation arrangements and the benefit-cost analysis of the proposed extensions.

The Board has reviewed both ProGas' and WGML's estimates of reserves and productive capacity and has compared these estimates with its own. With respect to ProGas the Board is satisfied that the applicant has sufficient reserves to meet its sales requirements. It is the Board's view that the minor productive capacity shortfalls estimated by both ProGas and the Board can be easily corrected by increasing takes from the applicant's current producers or by developing additional reserves from its currently contracted lands.

Although the Board is satisfied that WGML/TransCanada has sufficient gas supply to meet its current contracted domestic and export sales requirement (including the proposed extension) it notes that WGML will have to obtain new supplies in order to continue to extend its current contractual commitments.

Assuming evergreening, both WGML's and the Board's assessments of productive capacity associated with TransCanada's contracted reserves indicate that there will be insufficient productive capacity beginning as early as 1995.

The Board is familiar with the markets, sales contracts and transportation arrangements underlying the proposed licence extensions. In this regard the Board is satisfied that the U.S. buyers will continue to be valued long-term customers.

Finally the Board is of the view that, based on the benefit-cost analysis submitted by the applicants as well as the Board's own analysis, the present value of the sales will continue to be positive over the extended terms.

J.-G. Fredette
Presiding Member

J.R. Jenkins
Member

K.W. Vollman
Member

Amended Terms and Conditions of ProGas' Export Licence No. GL-98

Conditions 1, 2, and 6 of export Licence No. GL-98 will be revoked and substituted therefor will be the following:

"1. The term of this Licence shall commence on 13 August 1986 and end on 31 October 2000."

"2. Subject to condition 6, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

(a) for the period commencing on 13 August 1986, and ending on 31 October 1986, 9 440 900 cubic metres in any one day, or a total quantity of gas that may be exported under this Licence, and under Licence GL-56 until the date of repeal thereof, which shall not exceed 3 100 000 000 cubic metres during the period commencing on 1 November 1985 and ending on 31 October 1986;

(b) for the period commencing on 1 November 1986, and ending on 31 October 1987, 7 552 700 cubic metres in any one day, or 2 480 000 000 cubic metres in the period;

(c) for the period commencing on 1 November 1987, and ending on 31 October 2000, 9 440 900 cubic metres in any one day, or 3 100 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(d) 42 225 000 000 cubic metres during the term of this Licence, less the total quantity of gas exported under Licence GL-56 until the date of repeal thereof."

"6. The quantity of gas that may be exported at Monchy, Saskatchewan shall not exceed fifty percent of the total quantities of gas authorized for export during each of the periods specified in condition 2."

Amended Terms and Conditions of TransCanada's Export Licence No. GL-83

Conditions 1, 2, 3, and 5 of export Licence No. GL-83 will be revoked and substituted therefor will be the following:

"1. The term of this Licence shall commence on 1 November 1984 and end on 15 January 2003."

"2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

(a) for the period commencing on 1 November 1984, and ending on 31 October 1986, 1 133 100 cubic metres in any one day, or 414 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

(b) for the period commencing on 1 November 1986, and ending on 15 January 2003, 2 620 300 cubic metres in any one day, or 959 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 16 371 000 000 cubic metres during the term hereof."

"3. (1) As a tolerance, the amount that WGML/TransCanada may export in any 24-hour period under the authority of this Licence may exceed the daily limitations imposed in condition 2 by ten percent.

(2) As a tolerance, the amount that WGML/TransCanada may export under the authority of this Licence in any calendar month may exceed the quantity allowable during that period by two percent.

(3) As a tolerance, the amount that WGML/TransCanada may export in any twelve-month period under the authority of this Licence may exceed the annual limitations imposed in condition 2 by two percent."

"5. During the period commencing on 16 January 2003, and ending on 15 January 2004, WGML/TransCanada may export a quantity of gas which has been paid for but not taken during the term of this Licence provided that:

(1) such quantity does not exceed 2 620 300 cubic metres in any one day;

(2) such quantity does not exceed the lesser of the quantity of gas paid for but not taken, or the annual quantity of 959 000 000 cubic metres; and that

(3) at least six months prior to the commencement of the exportation of this gas, WGML/TransCanada demonstrates to the satisfaction of the Board that there exists sufficient surplus, deliverability, and pipeline capacity to permit this export."

Table A-1

Comparison of Productive Capacity Forecasts
(Petajoules)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity	ProGas Adjusted Productive Capacity	ProGas Spare Capacity
	(1)	(2)	(3)	(4)	(5)
1988	115	305	189	115	-
1989	115	303	187	115	-
1990	195	301	106	195	-
1991	213	297	85	213	-
1992	221	293	71	221	-
1993	224	283	59	224	-
1994	224	276	52	224	-
1995	224	264	40	224	-
1996	224	247	23	206	-18
1997	224	228	4	194	-30
1998	224	206	-18	180	-44
1999	224	186	-38	162	-62
2000	109	159	51	109	-
2001	109	139	31	109	-
2002	109	110	1	109	-
2003	109	60	-48	91	-18
2004	109	46	-63	77	-32
2005	60	36	-23	60	-
2006	38	30	-7	38	-
2007	29	26	-3	29	-
2008	29	23	-5	29	-
2009	29	21	-8	29	-
2010	5	19	15	5	-

Notes:
Col. (1) = ProGas' estimated total demand.
Col. (2) = Adjusted Productive Capacity using NEB's reserves estimates
Col. (3) = Col. (2) - Col. (1)
Col. (4) = Productive Capacity projection submitted by ProGas
Col. (5) = Col. (4) - Col. (1)

Table A-2

Comparison of Productive Capacity Forecasts
(Petajoules)

Year	Estimated Total Demand	TCPL Adjusted Productive Capacity	TCPL Spare Capacity
	(1)	(2)	(3)
1988	1076	2108	1032
1989	1175	2100	925
1990	1191	2036	845
1991	1395	1944	549
1992	1375	1830	455
1993	1393	1678	285
1994	1409	1557	148
1995	1410	1330	-80
1996	1410	1244	-166
1997	1410	1193	-217
1998	1407	1142	-265
1999	1407	1104	-303
2000	1316	1065	-251
2001	1316	1012	-304
2002	1316	936	-380
2003	1316	815	-501
2004	1315	738	-577
2005	1308	680	-628
2006	1308	628	-680
2007	1308	576	-732
2008	1308	532	-776
2009	1308	456	-852
2010	1308	420	-888

Notes: Col. (1) = WGML's estimated total demand
Col. (2) = Productive Capacity projection submitted by WGML
Col. (3) = Col. (2) - Col. (1)

Table A-3

Comparison of Productive Capacity Forecasts
(Petajoules)

Year	Estimated Total Demand	NEB Adjusted Productive Capacity	NEB Spare Capacity
	(1)	(2)	(3)
1988	1287	2093	806
1989	1445	2005	560
1990	1351	1897	546
1991	1230	1773	543
1992	1146	1662	516
1993	1136	1555	419
1994	1152	1443	291
1995	1152	1280	128
1996	1149	1153	4
1997	1133	1016	-117
1998	1100	873	-227
1999	1080	748	-332
2000	990	645	-345
2001	990	482	-508
2002	990	345	-645
2003	990	298	-692
2004	838	261	-577
2005	837	235	-602
2006	825	191	-634
2007	825	170	-655
2008	825	147	-678
2009	825	127	-698
2010	825	104	-722

Notes: Col. (1) = WGML estimated domestic demand plus currently authorized exports
Col. (2) = Adjusted Productive Capacity using NEB's reserves estimates
Col. (3) = Col. (2) - Col. (1)